Australian Competition & Consumer Commission

Discussion paper
Review of the regulatory test

5 February 2003

Contents

Glossary

CAISO	Californian Independent System Operator
COAG	Council of Australian Governments
Code	National Electricity Code
Commission	Australian Competition and Consumer Commission
CPUC	Californian Public Utilities Commission
DNSP	Distribution Network Service Provider
EME	Edison Mission Energy
ESAA`	Electricity Supply Association of Australia
HHI	Hirschmann-Herfindahl Index
IRPC	Inter Regional Planning Committee
LRMC	Long Run Marginal Cost
MNSP	Market Network Service Provider
NDR	Network and Distributed Resources
NECA	National Electricity Code Administrator
NEDF	National Electricity Distributors Forum
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NET	National Electricity Tribunal
NPV	Net Present Value
NSP	Network Service Provider
Opex	Operating Expenditure
RNPP	Tasmanian Reliability and Network Planning Panel
RSI	Residual Supply Index
SCL	Stanwell Corporation Limited
SHT	Snowy Hydro Trading Propriety Limited

SNI	South Australia – New South Wales Interconnector
SOO	Statement of Opportunities
SPI	SPI PowerNet
SRMC	Short Run Marginal Cost
TNSP	Transmission Network Service Provider
VENCorp	Victorian Energy Networks Corporation
VoLL	Value of Lost Load
USE	Un-served Energy
WACC	Weighted Average Cost of Capital

1. Introduction

On 19 June 2001, the Australian Competition and Consumer Commission (Commission) and the National Electricity Code Administrator (NECA) released a joint statement announcing their commitment to review the current regulatory framework for essential new investment. The statement noted that the existing arrangements for the planning and approval of regulated network investment have been widely criticised. As a result, the statement recognised that there is a need to streamline and simplify the arrangements whilst encouraging a nationwide approach to planning and strengthening the transmission network.

For its part, the Commission stated that it would review the regulatory test to ensure that it does not result in a complex and lengthy process that delays the development of regulated investment. The Commission also stated that it would consult widely as part of its review.

To this end, the Commission released an Issues Paper on 10 May 2002, which highlighted a number of concerns raised by interested parties with the operation of the current regulatory test. The Commission received 19 submissions. A list of parties who provided submissions is outlined in Appendix B. Submissions to the Issues Paper are available on the Commission's website (www.accc.gov.au).

From the submissions to the Issues Paper, the Commission has identified three options for the development of the regulatory test which are outlined in Chapter 3 of this Discussion Paper. The Commission invites interested parties to consider and comment on these options.

Submissions can be sent electronically to: electricity.group@accc.gov.au. Alternatively, written submissions or submissions on disk, in either Word 7.0 or PDF format, can be sent to:

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The closing date for submissions is **Friday 28 March 2003**.

Comments provided by interested parties will be incorporated into the Commission's draft decision. The Commission will consult on its draft decision prior to releasing its final decision where, if necessary, in accordance with clause 5.6.5A of the code, the Commission will promulgate changes to the regulatory test. The Commission considers that the regulatory test will ultimately form part of its Regulatory Principles.

2. Submissions

The Commission’s Issues Paper of 10 May 2002 raised a number of questions for interest parties to comment on. This chapter of the Discussion Paper summarises submissions from interested parties. The summary of submissions from interested parties appears in the same order as they appear in the Issues Paper. Where interested parties grouped their responses the Commission has attempted to summarise the main points.

For background on the development of the regulatory test, the Commission refers interested parties to Chapter 3 of its Issues Paper.

2.1 Maximising net market benefits

The regulatory test uses a cost-benefit framework so that an optimal outcome is identified and not just any option that generates a net public benefit or a positive Net Present Value (NPV). Therefore, a new interconnector or an augmentation option satisfies this test if it maximises the NPV of the market benefits having regard to a number of alternative projects, timings and market development scenarios.

What the interested parties say

Is the maximising-market benefits test is a hurdle that is too high?

Loy Yang, Origin Energy (Origin), NRG Flinders (NRG), Edison Mission Energy (EME), TransÉnergie, and VENCorp contend that the maximising net benefits to the market hurdle in the regulatory test is appropriate and consistent with the principles of economic efficiency.

The Reliability and Network Planning Panel (RNPP) is of the view that there should be a threshold applicable at the project level, defined in terms of minimum service standards by location:

- for projects below the threshold, a cost-effective test should apply; and
- for projects at the threshold or above the threshold, the market benefits test should apply.

Should the test simply refer to a nominated Net Present Value hurdle?

If so, what should the nominated hurdle be?

If adopted, how should the industry/users be protected from inefficient investment options ie high cost/low benefit solutions?

SPI PowerNet (SPI), EME, Loy Yang, NRG and VENCorp contend that a nominated NPV would fail to maximise the potential value of a regulated investment to the market among available alternatives. Further, VENCorp states that setting a nominated hurdle would raise questions as to who would set the hurdle, what its basis might be, and what supplementary arrangements would be required to safeguard against inefficient investment.

What other alternatives should be considered?

EME suggests that in addition to the current hurdle, augmentation proposals should demonstrate:

- a positive NPV (based on a commercial discount rate) for at least 90% for the set of market scenarios studied;
- that the NPV crossover should not exceed (100%/n%) where n% is the commercial discount rate to be applied; and
- that the proposal must show that under any reasonable scenario studied that the potential loss of benefits (stranded benefits) will not exceed 20% of the initial asset value.

Does the regulatory test need to differentiate between TNSPs and DNSPs?

EME, Loy Yang, the National Electricity Distributors Forum (NEDF) and SPI submit that the test for distribution networks should be consistent in principle, as the same economic objectives apply. NEDF states that some discretion should be allowed in the application of the test between transmission and distribution networks, to recognise existing jurisdictional controls and the scale, complexity and number of investments at different levels of the network.

NRG states that it may be possible to draw a distinction between the treatment of DNSPs and TNSPs for the purposes of the test, but only to the extent that the projects in question are not substitutes for each other. In the case of main system augmentation, a given project may have both distribution and transmission network alternatives. In areas of substitutability, it contends that it is essential that equitable and consistent treatment applies.

Is the current test dealing with reliability-driven augmentations appropriate?

Should reliability-driven augmentations follow a similar process to market driven augmentations?

EME submits that the current test is not appropriate. It argues that the proposed reliability augmentations are highly uncertain but are captured as if they would otherwise be committed projects, and therefore that no reliability augmentations should be allowed beyond five years, to reflect the high degree of uncertainty. It says that where a project is justified on the basis of reliability, it should be required to be delayed to the last possible time in order to meet the reliability requirement. EME argues that this will delay the project until reliability benefits are more certain and ensure that regulated investments do not crowd out innovative entrepreneurial solutions.

SPI, VENCorp and ElectraNet SA state that the reliability criteria should be justified in their own right. VENCorp strongly suggests that a review of the definition of "reliability augmentation" and any associated standards in Schedule 5.1 of the code should be undertaken by an independent body, and clarified as a matter of urgency. It submits that some TNSPs have interpreted Schedule 5.1 as mandating an "N-1" level of reliability. VENCorp argues that in comparison to its economic test, in some circumstances, the deterministic approach applied in other jurisdictions will lead to a higher level of investment than that which is justified economically using VENCorp's evaluation approach.

VENCorp also states that the adoption of materially different planning criteria by different TNSPs raises questions as to the basis of inter-regional TUoS charges, and urges the Commission to carefully consider the issue of inter-regional consistency of transmission investment criteria.

Origin notes that the test for reliability augmentations does not require 'net market benefits' to be maximised, nor is it subject to dispute. Origin and TransÉnergie submit that the current rules do not ensure that TNSPs are correctly classifying projects as reliability augmentations, and support a competitive tender process for the proposal and evaluation of reliability augmentations. Both parties also argue that the test implicitly assumes that only TNSPs can provide reliability solutions, and at a lower cost than any other party, making it difficult for private investments to compete with regulated options. Origin argues that ideally there should be no distinction made between reliability and other augmentations, but that this issue would disappear with an appropriately constructed governance framework that separates planning from ownership and allows for the tendering of network solutions.

TransÉnergie states that where a number of alternative market based solutions are proposed, the TNSP should be obligated to evaluate all proposals, including any of its own options, by either maximising the net benefits or minimising the net costs in accordance with the Regulatory Test.

Loy Yang, Powerlink, and NEDF agree that the current test for reliability augmentations is appropriate. However, Powerlink and TransGrid argue that any changes to the test must ensure that accountability for delivering transmission reliability remains linked to the ability of the accountable party to plan and invest accordingly.

TransGrid also questions whether the net market benefit limb of the test can be applied to augmentations identified under clause 5.6.2(c) of the code, and whether the status of a proposed augmentation as "reliability" has any bearing on whether limb(a) or (b) of the test should be used. TransGrid also seeks clarification on regulated projects still being considered under the grandfathered provisions of the code prior to the NDR code changes.

Should reliability driven augmentations be required to follow a similar process to market driven augmentation?

EME, Loy Yang, NRG, SPI and VENCorp believe that reliability driven augmentations should follow a similar level of scrutiny as other augmentations to allow net benefits to be maximised.

Powerlink submits that the development of criteria to determine whether an augmentation is a reliability augmentation should not be a matter that is open for consideration under the regulatory test review. It states that the code provides sufficient checks and balances to ensure that appropriate assessments are made. NEDF states that the principles of the regulatory test should apply in an even-handed manner across all investments, but that it is convenient and appropriate to categorise the types of investment.

2.2 Competitive impacts of network investment

The Commission acknowledges that network investment, and interconnectors in particular, can have a major impact on competition in a region, either by reducing generator market power or reducing prices. The Issues Paper notes that one of the concerns raised by NEMMCO's interconnector process working group is that the regulatory test does not fully recognise these competition benefits and that the test should be modified to do so.

What the interested parties say

Should the test be altered to reflect greater competition in a region from the introduction of network investment?

CS Energy, ElectraNet SA, EME, Enertrade, Powerlink, TransGrid, and Stanwell believe that competition benefits should be included in the market benefit stream of the regulatory test. EME and CS Energy note that participant behaviour may make it difficult to quantify competition aspects and avoid arbitrary assessment by proponents. SPI, TransÉnergie, and VENCorp also support the inclusion of competition benefits in the regulatory test, but consider that fundamental market power issues should be examined first. However, VENCorp comments that broadening the scope of the regulatory test to attempt to capture the benefits of competition raises policy issues that should be addressed separately and transparently by the Jurisdictions.

TXU states that the competition benefits appear to contradict regulatory practice regarding market efficiency and the need for more straightforward test. TXU further states that evaluating competition benefits would be extremely problematic and challengeable. It questions how a transmission planner is to estimate the level of market failure in the future, and how market power is to be evaluated.

NEMMCO recommends caution before attempting to include competition benefits into the regulatory test. It states that the revised test would need to be robust over a range of market development scenarios including a number of bidding scenarios. NEMMCO also considers that assessment of competition benefits based solely on a single bidding scenario be it SRMC or historical bidding could not be regarded as producing a representative outcome and would not be suitable for assessing the competition benefits of a new interconnection.

TransGrid does not argue for competition to be included in the test as a previously unallowed benefit, but as a means of more accurately calculating a higher market benefit. It supports a general equilibrium analysis of the competition benefits, to be carried out by the proponent, with the Commission having the right to allow or disregard these benefits, based on the merits of each case. It argues that a comprehensive way to account for the competition benefits of network options would be to include the general equilibrium (or indirect) benefits of lower electricity prices, where the Commission is satisfied with the rigour of the underlying quantifying analysis provided by the proponent.

Similarly, Stanwell supports an examination of changes in consumer and producer surplus, but states that it is inappropriate to use market prices as a proxy for competition levels. Therefore, Stanwell proposes the use of a competition level index, which should incorporate the following information:

- the number of consumers currently affected by the network limitation;
- the incremental electricity capacity supplied to the market following augmentation;
- the fuel mix of the incremental electrical capacity (indicating underlying cost structure); and
- the number of independent entities supplying the market following augmentation.

Stanwell considers that the competition level index will assist in more network augmentations, both within and between regions, passing the test under paragraph (b) of the regulatory test.

Origin, NRG and Loy Yang do not support the inclusion of competition benefits in the regulatory test. Origin states that given demand inelasticity for electricity, low prices would largely reflect wealth transfers rather than an increase in social surplus, and that there are no ‘net market benefit’ grounds for considering such benefits, while they provide regulated network investments with an advantage over non-regulated alternatives. NRG submits that network developments provide potential competitive benefits only to the extent that sufficient generation is available to enable the transfer of additional energy, where it cannot be assumed that such capacity will be available indefinitely. Loy Yang states that the objective of the test is to maximise the economic efficiency of a regulated investment, not for regulated investment to increase competition to drive efficiency.

If so, how should the benefits of greater competition be captured by the test?

Powerlink suggests that the regulatory test could be expanded to include an option “public benefit test”, which would provide the option to incorporate competition and other benefits under certain special circumstances. Powerlink explains that the “public benefit test” need not be prescriptive, but could indicate a range of benefits that a proponent might use in the regulatory test assessment, such as the inclusion of actual pool price outcomes, the consideration of strategic bidding scenarios, and major load development scenarios. Powerlink notes that this would add significant volatility to the test and increase disputes, and recommends that it only be used in certain circumstances where the benefits are significant and relatively clear-cut.

Powerlink suggests that such circumstances might include:

i. where historical evidence exists that wholesale prices have been significantly above marginal costs;

ii. where market power occurs or will occur, necessitating a definition of when market power arises;[1] and

iii. where overcoming a particular network limitation is considered sufficiently important by one or more jurisdictions. This category could be determined by a jurisdiction to be 'in the state's interest', or if multiple jurisdictions are impacted such as in the case of an interconnector, 'in the national interest'.

Stanwell proposes the use of a competition level index, which would overcome what it sees to be problems associated with using market prices as a proxy for competition levels. Stanwell considers that the index should incorporate the following information:

- the number of consumers currently affected by the network limitation;
- the incremental electricity capacity supplied to the market following augmentation;
- the fuel mix of the incremental electrical capacity (indicating underlying cost structure); and
- the number of independent entities supplying the market following augmentation.

SCL considers that the inclusion of a competition level index will assist in more network augmentations, both within and between regions, passing the test under paragraph (b) of the regulatory test.

CS Energy recommends that reserve margins between available generation and demand at a given load centre are a good indicator of competitiveness and hence might be used as a proxy for competition benefits.

Enertrade and EME support modelling of pool prices. Conversely, Loy Yang states that incorporation of competition benefits even if they could be quantified is not practical as they are subjective and unreliable and difficult to incorporate into any cost benefit analysis. NEMMCO states that indices of competition can be calculated but that it is difficult to value an increase in competition so that it can be compared with the other costs and benefits of proposed interconnection projects or their alternatives. It advises that the revised test would need to include a range of market development scenarios, including a number of bidding scenarios, but that an assessment based solely on a single bidding scenario, such as SRMC or historical bidding would not be representative of the competition benefits of new interconnection.

NRG states that it is important to focus only on the incremental benefits of a network augmentation. It argues that there is a clear distinction between the impacts of an initial interconnect linking NEM regions, with its associated competitive and reserve sharing benefits, as opposed to the impact of subsequent interconnections. It adds that

1 Powerlink refers to the Australian Bureau of Agriculture and Resource Economics (ABARE) definition of generator market power for an explanation of this.

the marginal value of each new interconnector will diminish as the number of interconnects increases.

If a proposed network investment is marginal, should a competition test be included that allows the proposal to pass the test?

SPI and ElectraNet SA submit that consideration of competition benefits would be appropriate in the situation where the benefits are otherwise assessed to be marginal. SPI comments that a pragmatic approach outside of the market benefits analysis would be preferable.

EME, Loy Yang, and NRG do not support the use of a competition test in this situation. EME considers that it only be appropriate to do so if competition was already incorporated into the regulatory test. Loy Yang argues that the evaluation must be based on quantifiable benefits, not intangibles.

If so, what form should the competition test take?

SPI suggests that the competition benefits could be incorporated via some scenario-based assessment of average prices, but that total reliance on pool price modelling would be inappropriate. EME submits that the same approach as is to be used for the beneficiary pays test would ensure a rigorous analysis.

Should the benefits associated with additional capacity to meet peak demands in a region be included in the assessment of a new interconnector?

TransGrid, SPI and VENCorp agree that such benefits can be included in the assessment of a new interconnector, but that the benefits can be incorporated into the regulatory test as it currently stands. TransGrid comments that the benefits of deferring new capacity are already assessed as a benefit attributable to a network augmentation. Therefore, to the extent that an option leads to the deferral or avoidance of such developments, that benefit should (continue to) be included in the regulatory test calculations.

VENCorp explains that this is possible provided that an assessment is undertaken compared with a "Do Nothing" option, and that note (1)(b)(ii) of the regulatory test is amended to provide for the market benefit to be evaluated using the marginal value of supply reliability to consumers, instead of using the Value of Lost Load (VoLL) wholesale market price cap.

EME notes the benefits arising from the deferred capital costs of new generation development, but states that these benefits are highly uncertain and therefore should be limited to five years. It argues that the current modelling undertaken by NEMMCO probably overstates the benefits that would be obtained by an interconnector. Loy Yang states that it would be more appropriate to assume the reserve is established on the basis of the 0.002% Un-served Energy (USE) reliability level, which assumes that the competitive market will work. Based on this assumption, less reliability driven plant would be required and the benefits to regulated interconnectors would be assessed on a more conservative basis.

If a new interconnector results in lower prices in one or more regions (eg importing regions), should the benefits of lower prices be included in the test?

SPI argues that the inclusion of competition benefits is even more difficult to justify for interconnectors, as it implies significant market power in a region. Hence, SPI argues for the need to deal with the underlying reasons for the existence of market power. It further states that the inherent volatility in the outcomes of the assessment, in particular the subjectivity in modelling market behaviour in an environment where market power may be exercised, would make it difficult to draw clear conclusions of real benefits that are achievable.

Therefore, SPI states that where a new interconnector results in higher prices in one or more regions (eg exporting regions), the costs of the higher prices should not be included in the test.

EME submits that it sees some benefits in including lower prices as part of the test as it reflects some of the benefits that entrepreneurs could access. However, it states that as a wealth transfer does not enhance economic efficiency, any such approach must be undertaken rigorously to avoid arbitrary assessment by proponents.

Loy Yang states that if prices are to be included then both lower and higher prices should be included and the two would offset each other. It submits that it does not appear to be practical to include prices as they give widely diverging results and do not represent competitive outcomes.

How will taking into account competition benefits interact with who pays for the augmentation?

EME and SPI recommend that any approach to competition benefits that can be identified via the Regulatory Test should be consistent with the beneficiary pays test.

Should the test ensure an alignment between the beneficiaries of the investment with those who pay for it?

NEDF and EME support the alignment of the regulatory test with the beneficiary pays test, as it would streamline the process associated with large new investments.

Powerlink submits that the investment decision should be considered from the opposite viewpoint – that is, the beneficiaries pays mechanism should be developed so as to align with the regulatory test, not vice versa, and with the true (not theoretical) beneficiaries of an investment. It states the cost allocation process should not impact the investment decision – this would invite disputes from parties who do not wish to pay for an economically efficient investment.

Loy Yang argues that if the test demonstrates that an investment is the most economically efficient option, then customers will automatically benefit from that market development. It says that there is little point in trying to force an alignment based on a prediction of what might occur in the future.

Should regulated and unregulated network alternatives be treated in the same way in terms of the benefits (or detriment) associated with them?

SPI submits that assuming that the question relates to the treatment of the alternatives as options in the comparative analysis for a regulated proposal, then unregulated alternatives should be consistent in terms of the criteria by which benefits are identified.

EME, NRG, and TransÉnergie submit that it is necessary for both forms of investment to be treated on an equivalent basis to ensure competitive neutrality, avoid duplication of investments and avoid regulated investments distorting the competitive market.

2.3 Network and Distributed Resource code change package

The Network and Distributed Resources (NDR) code change package assigns the primary responsibility for the planning and development of transmission networks to TNSPs. Although the process is now time limited and contains a dispute resolution process, there may be some concerns that TNSPs have greater control over the design and approval of network augmentations. During the code change process parties raised concerns about the checks and balances in place to prevent a TNSP misusing its monopoly position and preventing the appropriate consideration of non-network options.

What the interested parties say

Should the regulatory test be more prescriptive?

ElectraNet SA, EME, Loy Yang, NEDF, TransÉnergie, and VENCorp support a more prescriptive regulatory test, to ensure competitive neutrality, clarify which costs and benefits should be taken into account, and reduce possibilities for dispute. However, ElectraNet SA states that the current code requirements for public consultation provide more than adequate checks and balances to ensure that alternative augmentation options, including non-network options, are considered.

TXU notes that where the regulatory test seeks to prove net market benefits is philosophically and economically sound given the nature of regulated investment, problems are then related to the implementation of the process, where influence can be used to bias the process to demonstrate a specific outcome. Therefore, TXU notes that it may be necessary to make the test more specific such that the process cannot be diverted away from the original philosophy, while making the test quicker and less open to dispute. It recommends the retention of the intent of the present regulatory test with certain clarifications to ensure the process is less open to influence from vested parties.

SPI states that if regulated augmentation remains the primary model to deliver network investment it will be necessary for the test to retain a degree of flexibility, and in particular that it should not preclude the necessary scenario analysis to evaluate the range of alternative projects.

VENCorp contends that the requirements of the regulatory test that relate to the number and type of non-network alternatives should be clarified, including alternatives that:

i. either have a clearly identifiable proponent; or

ii. have a real and reasonable chance of becoming an alternative without significant technological advances or process improvements taking place.

Should the test define which costs and benefits should be taken into account?

EME and Loy Yang state that the test should not define which costs and benefits should be taken into account. EME states that these should be considered on a case-by-case basis.

NEDF states that the test should define the relevant costs and benefits. Similarly, NRG supports greater guidance on costs and benefits to be included in the regulatory test in the interests of consistency across the NEM and certainty for participants.

Origin recognises that the Commission has sought to impose an incentive regime for TNSPs in regard to these matters, and therefore that the administrative and transaction costs of these measures should be included in the regulatory test.

Origin also considers that the current test takes insufficient account of key environmental benefits associated with local generation options, and that as a result, greater benefits are attributed to augmentations than a rigorous cost-benefit analysis would allow, to the advantage of regulated expansion of the network. ElectraNet SA comments that the wind farm developments that are expected to eventuate in response to the Commonwealth Government's greenhouse policy, are an example of the environmental benefits that might be included in the regulatory test.

NRG supports the exclusion of externalities (such as emissions) from consideration under the regulatory test until such costs are internalised, as it is not the role of the regulatory test to resolve these broader policy issues. However, NRG Flinders recommends greater guidance on the costs and benefits that may be included in the regulatory test to facilitate greater consistency in the market and certainty for participants. It considers that terms that may require definition include 'unforseen circumstances' resulting in project delay (note 7b), and 'material impact' requiring republication of information (note 9).

NRG also suggests that a requirement that a given proportion of net benefits should be realised within a reasonable forecast timeframe (eg 5 years) might be considered. It contends that it is questionable that a project can be justified on the basis of net benefits that were weighted heavily in the future years of the forecast period, recognising the increasing uncertainty attached to any estimates of future costs and benefits.

SPI and the New South Wales (NSW) Treasury submit that the current regulatory test should allow time for the market to provide alternative solutions to proposed augmentations prior to the time that a regulated solution is considered.

NRG suggests that the present test may allow for the consideration of a wider range of benefits than might be appropriate

If so, what should these costs and benefits be?

EME suggests that the test should set a reasonability limit to be applied to proponents' forecasts to ensure that unlikely benefits are not claimed and that costs are not forecast too optimistically. Similarly, NRG states that it appears questionable that a project could be justified on the basis of net benefits that were weighted heavily in future years of the forecast period, recognising the increasing uncertainty attached to any estimates of benefits and costs into the future. It therefore suggests a requirement that a given proportion of net benefits should be realised within a reasonable forecast timeframe (eg 5 years) might be considered.

Should the test include a glossary of definitions, and if so, which terms should be defined?

EME, ElectraNet SA, Loy Yang, TransGrid, NEDF, SPI and NSW Treasury state that a glossary of terms would enhance interpretation of the test.

TransGrid suggests the following terms be inserted into the regulatory test:

Augmentation:- The test defines "augmentation" as a proposal in accordance with the (pre NDR) code clause 5.6.2.

*Augmentation option: -*The test defines "augmentation option" as a proposal in accordance with the (pre-NDR) code clause 5.6.5. (TransGrid notes that the current clause 5.6.5 refers to augmentations identified as part of the IRPC's annual interconnector review).

*Proposed interconnector: -*The test defines "proposed interconnector" as a proposal in accordance with the (pre-NDR) code clause 5.6.6.

Proposed augmentation: - The test defines "proposed augmentation" as any of the above.

However, it notes that the above definitions are inappropriate following the NDR code changes, except that "proposed solution" could perhaps be used to cover any proposal under clauses 5.6.6 and 5.6.6A.

TransGrid argues that the current definition of "augmentation" in the code would lead to legal issues.

EME suggests the definition of all terms that are either inputs or that transform the inputs to the output used in carrying out the test. NEDF proposes the definition of the costs and benefits normally taken into account. It considers that a few worked examples (using a similar approach to that adopted for the Negotiation Guidelines) would be helpful in providing interpretation of the Commission's intentions. It states that such examples should provide an indication of the treatment required for projects involving different levels of complexity and market impact.

ElectraNet SA and NSW Treasury submit that a key issue in the application of the regulatory test is the meaning of "alternative" projects. NSW Treasury states that if the regulatory test is not restricted to an assessment of the net benefits of the proposed augmentation in question, then the nature of the competing alternatives to be compared needs to be clarified. ElectraNet and NSW Treasury agree that it should be put beyond doubt that "alternative projects" means "alternative non-regulated projects", or at least "alternative projects that do not involve regulated augmentation of the proponent's network".

NSW Treasury also states that the limiting of the test to comparison of regulated projects with alternatives to regulated augmentation of the relevant TNSP's network does not create a barrier to a third party proposing a regulated option. Further, the contestability of regulated projects allows a market for the regulated project to be nurtured, whereby the party that proposes and assesses a regulated augmentation first can apply the test with the protection that if the project passes the regulatory test, it cannot be imitated by another party. NSW Treasury argues that once the test has been successfully applied to a regulated project, that project should be regarded as "committed" or "anticipated" and a follower proponent would have to take the project into account in assessing its own regulated option, if it chose to continue with the assessment. Other possible indicia of "committed" status could be undertaking an Environmental Impact Study or commencement of physical construction. It would be useful if the Commission could provide some guidance to proponents in this regard.

TransGrid supports a proposal where for a project to be deemed as "committed", the proponent should be required to lodge some form of non-refundable bond (eg 5% of expected project costs), unless it has reached an irreversible stage of development. This will demonstrate that it is certainly more economic for the project to be completed than left incomplete. A similar bond, albeit smaller (eg 1%), should be submitted for "anticipated" projects. TransGrid explains that the purpose of a bond would not be to create a barrier to entry for unregulated projects, but to reduce the risk of gaming of the regulatory test by vested interests.

Should a market test period, in which unregulated alternatives to network investment are given a specified time to respond to constraints identified by the network, be introduced into the test?

EME, Loy Yang, SPI, NRG, and VENCorp support the introduction of a market test period. SPI states that this is appropriate if the current regulated transmission planning and investment arrangements remain, on the basis that the test aims to maximise the net benefits – which could be provided by a non-regulated option.

Origin, Loy Yang and TransÉnergie support a market test period, combined with measures to address the current information asymmetry in relation to network technical information, as this is a factor that impacts competitive neutrality, because the MNSP proponent does not have ready access to the data. Origin states that this provision would rely critically on the disclosure of information by TNSPs, but believes that the current framework does not provide appropriate incentives for this to occur.

NRG states that the present test may be considered a limited time frame in which to bring a market driven investment to commitment stage. It suggests that clarifying the application of the market failure test would bring the lead-time up to 30 months, but it may be worthwhile to extend the timeframe, at least for non-reliability projects.

VENCorp states that the timing and duration of a "market test period" must be set in a manner that recognises the uncertainties associated with forecasting load growth, identifying emerging constraints, and timing any remedial action so as to optimise economic outcomes. The test period should also recognise the lead-time associated with network-based solutions to emerging network constraints.

Powerlink and TransGrid do not support the market test period. Both comment that the NDR code changes introduced prescriptive requirements for TNSPs to provide greater disclosure via the Annual Planning Reports and consultation processes. Similarly, ElectraNet SA believe that sufficient provision for this already exists within the regulatory test.

SHT argues that the onus must be on TNSPs to identify potential future network constraints and to make this information available to the market. It states that market participants must then be given a sufficient amount of time to assess the viability of privately funded alternatives to alleviate the potential constraints. If market participants don’t respond to address the constraint then it is a clear indication that there are no benefits likely to accrue to the participant by addressing the constraint. Hence, the benefits must default to customers and therefore any regulated transmission project subject to meeting the requirements of the regulatory test must be funded by market customers.

What special provision should be introduced for DNSPs to assist them and the market to ensure that the most appropriate investment is pursued?

SPI comments that it would expect a generally simpler assessment within the DNSP environment based on a similar market benefits test.

2.4 Timing delays

One of the criticisms of the regulatory test relates to the time taken to approve an interconnector under the current arrangements. For example, SNI was approved in December 2001, two years after it had been submitted to the Inter Regional Planning Committee (IRPC) for assessment. One of the major benefits of the NDR code changes is that the IRPC, dispute resolution panel and the Commission are time constrained in their assessment of a regulated proposal.

What the interested parties say

Have the problems of time delays been sufficiently addressed in the network and distributed resources code change package?

ElectraNet SA, NEDF, SPI and Stanwell submit that the code changes have assisted in reducing delays.

SPI states that time delays occur largely because the regulated transmission proposals are not directly agreed between the TNSP and the market participants that the proposals will serve. It contends that a competitive transmission augmentation framework would reduce reliance on the regulatory test, and hence the associated delays.

Stanwell argues that delays occur because the regulatory test requires TNSPs to explore all alternative options before new assets are incorporated into their asset base. Stanwell believes that this also discourages future generation investment. Consequently, it recommends a time limit being placed on unregulated alternatives when responding to constraints identified by the network.

ElectraNet SA contends that in general, further streamlining of the approval process can be achieved by raising the $1 million and $10 million thresholds defining new small and large network assets. It explains that at present, a routine transformer replacement, which might cost $2-3 million, would be subject to the public consultation processes set out in the code, with little if any value to be gained from the cost of doing so.

EME, Loy Yang and TransÉnergie agree that the code changes have provided reasonable timeframes for the assessment of proposals, but that no further changes are necessary.

TransGrid argues that following the NDR code changes there is potential for ambiguities in the code and the regulatory test to create lengthy delays in the assessment of regulated projects. It therefore cautions against the regulatory test creating further interpretation difficulties that would contribute to the risks of lengthy disputes.

2.5 Other issues for consideration

Parties who have been involved in the previous regulatory test processes have raised the following as issues to be addressed.

Should the Commission clarify its optimisation of network investment that has been assessed in accordance with the regulatory test?

EME, ElectraNet SA, Loy Yang, NEDF, TransGrid and SPI agree that the Commission should articulate its policy on optimisation. SPI submits that the Commission should clarify how it would apply its principles to new investment that has passed the regulatory test, particularly with regard to whether benefits are realised by the proponent or by customers. SPI states that in doing so, it may become clearer whether the Commission should perform the role of final adjudicator for approval under the regulatory test.

ElectraNet SA argues that investments that have passed the regulatory test should not be subject to optimisation, but if this position is not accepted, then the proponent of a regulated investment should be given greater freedom to apply the test with minimal intervention from the regulator or other parties.

CS Energy believes the risk of optimisation is an impediment to investments proceeding in a timely manner. Its view is that regulated business should receive low returns commensurate with low levels of risk. To achieve this aim, CS Energy suggests two alternate ways of handling the issue of optimisation. One option would be to reduce the return on assets to values just above prevailing cash rates and abolish optimisation of assets. Another option would be for the return on assets to be maintained at current levels and reduce returns on optimised out assets to cash cost only, not zero.

Stanwell believes a change to the Commission's process is necessary and proposes the following options:

i. the Commission review each regulatory test decision prior to the commencement of the augmentation; or

ii. the Commission could guarantee a significant proportion (eg 80%) of the augmentation investment on finalisation of an investment decision made under the regulatory test.

Should the test address the weighting of outcomes? If so, how can this be achieved?

EME, SPI and Loy Yang comment that weighting of outcomes is arbitrary and subject to manipulation, and is therefore unlikely to be helpful.

Is the choice of discount rate, being the rate appropriate for the analysis of a private enterprise investment in the electricity sector, still appropriate?

EME, SPI, Origin, SHT, Loy Yang and NRG believe that the use of a discount rate for regulated investments is appropriate, and should be consistent with the uniform treatment of regulated and unregulated projects. The RNPP states that the discount rate should be commensurate with the rate applied by commercial enterprises facing similar risks (low risk, but high impact) and the WACC used at the last regulatory revenue reset adjusted for changes in the environment.

ElectraNet SA, VENCorp and TransÉnergie submit that the regulatory test should have discount rates closely linked to the determination of a commercial WACC. TransÉnergie states that for instance, if a lower discount rate is used in the regulatory test, effectively signalling that there is less risk of the benefits being achieved, then the revenue cap determination should reflect a similarly lower WACC.

The NEDF considers that a discount rate appropriate for private investment will not provide the appropriate outcome for regulated network investments in all circumstances. It explains that the existing networks have been progressively developed, using a discount rate appropriate for relatively low risk investments. The networks are largely optimal and within regions, have relatively low costs of losses and generally small levels of out of merit generation, which continue to benefit customers.

NEDF submits that to move towards a cost of capital reflecting higher risk would result in an inappropriately short-term focus for investments, resulting in a move to the minimum sized, least capital cost solution. It states that this would be accompanied by

- much higher cost of losses;
- risk of non-supply, where this is factored into account;
- out of merit generation; and
- operating expenditure (Opex).

NEDF also states that the pricing associated with regulated network investments reflects their economic life and would not be aligned with the investment process, and that this approach would be of particular concern if applied to regulated network investments designed to meet specified regulatory reliability standards.

Should there be specific requirements for competitive tendering that could form the basis of a safe harbour provision?

SPI comments that competition in the provision of transmission services is a first step toward delivering competitive and market integrated transmission augmentation and on this basis is supported by SPI. However, it states that the question of competition within the planning process remains, and that only a market led investment regime will provide truly competitively valued solutions.

TransGrid, Loy Yang and EME do not support this option, but for different reasons EME submits that competitive tendering only deals with costs and does not ensure that the benefits exist with a high degree of certainty. It states that in order for an investment to be approved it must demonstrate benefits and remain subject to optimisation at each regulatory reset period (based on changes to assessed benefits). EME comments that competitive tendering should be used anyway to ensure that the cost of any project is minimised. Conversely, TransGrid argues that before the test is changed to require competitive tendering for entire solutions to forecast constraints or meeting a network performance standard, the Commission should clarify whether tendering would insulate the project from subsequent optimisation.

3. Regulatory test options

This chapter of the Discussion Paper draws on submissions to the Issues Paper and considers possible amendments to the regulatory test that may improve its application. Based on submissions to the Issues Paper, the Commission outlines three possible options for consideration:

1. maintaining the current test with minor modifications to ensure consistency between the regulatory test and the code following the NDR code changes;

2. define and clarify elements of the regulatory test to ensure a consistent application of the test across the NEM; and

3. outline possible methods for assessing competition benefits.

The Commission notes the possibility of combining the options identified above. This would include:

- option 1;
- option 1 and 2;
- option 1 and 3; and
- option 1, 2 and 3.

The Commission seeks comments from interested parties on the appropriateness of the options outlined as well as what the appropriate combinations of these options are.

3.1 Minor amendments

3.1.1 Introduction

As noted in chapter 2, most interested parties support the retention of the maximising net benefits test arguing that it is the appropriate test to apply to network investments and is consistent with the principles of ensuring that only efficient and prudent investments are granted regulated status. As a result, one option that the Commission is considering is for the regulatory test to remain in its current form with minor amendments to ensure consistency between the regulatory test and the code.

The Commission believes that this option is appropriate considering the alignment of the responsibilities between the planning and construction of network investments in the code following the NDR amendments. This option provides the market with an opportunity to adapt to the current code arrangements and determine whether they facilitate efficient network investment or require complementary amendments to the regulatory test.

The Commission also notes that there are several advantages in maintaining the regulatory test in its current form. The regulatory test has been applied on a number of occasions in its current form and there is an understanding on how it is to be applied. Further, the regulatory test has now been subject to an appeal to the National Electricity Tribunal (NET).

Below, the Commission presents a summary of the NDR code changes, and what it considers to be the appropriate amendments to the regulatory test to align it with the code. The Commission is also consulting on whether the current distinction between new large and small network assets in the code is appropriate and whether replacement assets and refurbishments should be subject to the regulatory test.

3.1.2 Network and Distributed Resource code changes

The NDR amendments introduced two major changes to the code. Firstly, the code amendments devolved responsibility for the application of the regulatory test relating to inter-regional augmentations from NEMMCO to the TNSPs. Secondly, the amendments removed and replaced the distinction between inter and intra-regional network augmentations with new large and small network assets.

The code requires that a TNSP's Annual Planning Report contain detailed information concerning all proposed augmentations to the network. Specifically, in relation to new small network assets, the code requires information concerning the ranking of reasonable options to the project, a technical augmentation report (if required) and why the TNSP considers that the asset satisfies the regulatory test. The TNSP must consult with any interested parties about the proposal and develop a revised report on the proposal if any material matters change. The Commission is required to take into account this report in the process of its determination of the TNSPs' revenue cap and whether the network asset satisfies the regulatory test.

A party seeking to establish a new large network asset is required to develop an application notice and to go through a more rigorous approval process than with a new small network asset. The process may involve three key stages:

1. consultation on the application notice;
2. dispute resolution if certain matters remain disputed; and
3. should an interested party dispute the findings in an applicant's final report that the new large asset satisfies the regulatory test, a Commission determination on whether or not the new large network asset satisfies the regulatory test.

While the proposals were developed with transmission network planning in mind, NECA modified the code to ensure that the existing provisions and obligations on DNSPs were maintained but not extended. That is, DNSPs must continue to carry out economic cost effectiveness analyses of options that satisfy the regulatory test where it has identified necessary augmentations in its annual planning review[2]. NECA is intending to undertake further work with the industry and jurisdictional regulators on how the general principles applied to TNSPs might apply to DNSPs.

2 Clause 5.6.2(a2)(g)

Therefore, in light of the arrangements the Commission considers that it may be appropriate to allow the market to adapt to the new arrangements resulting from the NDR code changes before considering further amendments to the regulatory test.

3.1.3 Ensuring consistency between the regulatory test and the code

In its submission to the Issues Paper, NEMMCO indicated that changes to the regulatory test are required to ensure consistency between the regulatory test and the code. The Commission concurs with NEMMCO that the inconsistency in the terminology used could create confusion in its interpretation, and the cross-referencing between the regulatory test and the code may potentially open an avenue for dispute. The Commission considers that realigning the regulatory test with the code following the NDR amendments will provide uniformity between the code and the regulatory test, and less confusion and contradiction in its interpretation.

The Commission notes that there are three broad areas where the regulatory test and the code are inconsistent:

- the roles and responsibilities of NEMMCO, TNSPs, IRPC and the Commission in relation to planning and approval of new transmission network investments have been amended;
- reference to inter and intra regional augmentation in the regulatory test compared to small and large network assets in chapter 5 of the code; and
- other cross-referencing between the regulatory test and clauses of the code.

As a result, the Commission's proposed changes to the regulatory test are outlined below.

Preamble

Currently, the preamble to the regulatory test states:

> The Australian Competition and Consumer Commission promulgates this regulatory test in accordance with clause 5.6.5(q)(1) of the National Electricity Code (the Code).

Clause 5.6.5(q)(1) was deleted from the code and was replaced with the Annual Interconnector Planning Review to be undertaken by NEMMCO and the IRPC. As the application of the regulatory test to augmentation options is now applied by TNSPs, not NEMMCO and the IRPC, clauses 5.6.5 (f) to (q) were deleted. The Commission's ability to promulgate the regulatory test has been inserted in clause 5.6.5A(a) of the code.

The Commission considers that the preamble section of the regulatory test should therefore be amended to:

> The Australian Competition and Consumer Commission promulgates this regulatory test in accordance with clause 5.6.5A(a) of the National Electricity Code (the Code).

Reliability augmentations

Part (a) of the reliability limb of the regulatory test states

> An *augmentation* satisfies this test if -
>
> (a) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or

The code now states that a NSP must also consider relevant legislation or statutory instruments of a participating jurisdiction when undertaking reliability augmentations. The Commission believes that this section should therefore be amended to:

> An *augmentation* satisfies this test if -
>
> (b) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code or in relevant legislation, regulations or any statutory instrument of a *participating jurisdiction* – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or

Other amendments

The regulatory test currently states that:

The regulatory test is to be applied:

(a) to *transmission system* or *distribution system* augmentation proposals in accordance with clause 5.6.2 of the Code (*augmentation*);

(b) by NEMMCO and the Inter-regional Planning Committee to augmentation options identified under clause 5.6.5 of the Code other than applications for new interconnectors in accordance with clause 5.6.6 of the Code (*augmentation option*); and

(c) by NEMMCO and the Inter-regional Planning Committee to applications for new interconnectors across regions in accordance with clause 5.6.5 and 5.6.6 of the Code (*new interconnectors*).

In this test, *augmentations, augmentation options* and *new interconnectors* are called *proposed augmentations*.

As noted previously, NEMMCO is no longer responsible for applying the regulatory test to new interconnectors and NSPs are responsible for applying the test themselves. Further the changes removed and replaced the distinction between inter and intra-regional network augmentations with new large and small network assets.

Therefore, the Commission considers that the regulatory test should be amended as follows:

The regulatory test is to be applied:

(a) to transmission system or distribution system augmentation proposals in accordance with clause 5.6.2 of the Code (augmentation);

(b) by NSPs to *new small network assets* identified under clause 5.6.5 and pursuant to clause 5.6.6A of the Code, other than to a *new large network assets* in accordance with clause 5.6.6 *(new small network assets);* and *(c)* by NSPs to *new large network assets* pursuant to clause 5.6.6A of the Code *(new large network assets)*

In this test, *augmentations, new large network assets* and *new small network assets* are called *proposed augmentations*.

3.1.4 Other issues

Small and large network assets

As noted above, the Commission is of the view that to ensure consistency with the code, the regulatory test should refer to new small network assets and new large network assets.

A "new large network asset" is defined in Chapter 10 of the code as:

> "An asset of a *Transmission Network Service Provider* which is an *augmentation* and in relation to which the *Network Service Provider* has estimated it will be required to invest a total capitalised expenditure in excess of $10 million, unless the *ACCC publishes* a requirement that a *new large network asset* will be distinguished from a *new small network asset* if it involves investment of a total capitalised expenditure in excess of another amount, or satisfaction of another criterion. Where such a specification has been made, an asset must require total capitalised expenditure in excess of that amount or satisfaction of those other criteria to be a *new large network asset*."

A "new small network asset" is defined in Chapter 10 of the code as:

> *"An asset of a Transmission Network Service Provider which is an augmentation and:*
>
> *(a) in relation to which the Transmission Network Service Provider has estimated it will be required to invest a total capitalised expenditure in excess of $1 million, unless the ACCC publishes a requirement that an asset will be a new small network asset if it involves investment of a total capitalised expenditure in excess of another amount, or satisfaction of another criterion. Where such a specification has been made, an asset must require total capitalised expenditure in excess of that amount or satisfaction of those other criteria to be a new small network asset; and*
>
> *(b) is not a new large network asset."*

However, during the NDR authorisation assessment, interested parties raised concerns that the thresholds for the determination of a new large and small network asset was set too low. In its authorisation determination the Commission committed to review the clarification after some time. The Commission now asks that interested parties comment on whether the current classification between large and small network assets in the code is appropriate.

The regulatory test, replacement assets and refurbishments

The Commission is aware that there have been concerns raised in respect of whether replacement assets are subject to the regulatory test under the definitions of "new large network assets" and "new small network assets". The Commission sees clause 5.6.6 and 5.6.6A as requiring the regulatory test to be applied only to that part of an investment project that augments a network, as opposed to the replacement of existing assets.

For instance, if a TNSP proposes to construct a "new large network asset" it must comply with the process set out in clause 5.6.6. This will require an application of the regulatory test (unless the asset is a "reliability augmentation").

The terms "augment" and "augmentation" are defined in Chapter 10 of the Code as:

> "Works to enlarge a *network* or to increase the capability of a *network* to transmit or distribute *active energy*."

If the works being undertaken by a TNSP involve the construction of new assets in order to enlarge its network or increase its capability, then such works will be a new large network asset if they involve a total capitalised expenditure in excess of $10 million, and a new small network asset if they involve a total capitalised expenditure of between $1 million and $10 million. Conversely, if the capital works do no more than replace an existing asset, without enlarging the network or increasing its capacity, then the works will not be an augmentation and therefore will not be subject to the new large or small network asset provisions in the Code. Therefore, an NSP is not required to apply the regulatory test to refurbishment and replacement capital expenditure.

However, if a TNSP replaces an existing asset with one that simultaneously increases the capability of its network, the Commission is of the view that the part of the investment project that augments the network is subject to the regulatory test.

However, where the augmentation is not assessed against the regulatory test the Commission will conduct a thorough review of the capital expenditure undertaken by the TNSP and will assess the prudency of the expenditure against a criteria similar to that set out in the regulatory test. Where it finds that the capital expenditure is not efficient the Commission has the ability to optimise the inefficient portion out of a TNSPs asset base. TNSPs who voluntarily assess replacement or refurbishment capital expenditure against the regulatory test are less likely to face this optimisation risk.

3.1.5 Optimisation

The Commission acknowledges the response of interested parties to the issue of optimisation and will consider this issue further in its finalisation of the Statement of Regulatory Principles.

3.1.6 Conclusion

The first option that the Commission is considering in its review of the regulatory test is for the regulatory test to remain in its current form with minor amendments to ensure consistency between the regulatory test and the code. The Commission considers that the option outlined above provides a level of continuity following the amendments to the code. The NDR code changes address some existing shortcoming in the process for the assessment of network augmentations. The Commission notes that in any event, the regulatory test needs to be realigned with the code to ensure consistency in interpretation.

The advantages in maintaining the regulatory test in its current form with amendments to align it with the code is that it has been applied a number of times in its current form, it ensures continuity and it has been tested in the NET. The Commission considers that aligning the regulatory test with the code will provide consistency in the terminology used and less contradiction in their interpretation.

3.2 Definitional amendments

3.2.1 Introduction

As noted previously, the NDR code changes alter the respective roles and responsibilities of TNSPs, the IRPC, NEMMCO and the Commission in relation to the planning and approval of new transmission network investments. Under the NDR code changes, TNSPs will have primary responsibility for the planning and development of transmission networks. Although the process is now time limited and contains a dispute resolution process, there may be concerns that TNSPs have greater control over the design and approval of network augmentations.

A number of parties argue that now that the regulatory test is conducted by individual TNSPs, the Commission should take a more rigorous approach to defining the boundaries of the regulatory test. They also note that with multiple parties applying the regulatory test, they may see multiple and conflicting interpretations of its application being adopted to suit individual needs. Therefore, the second option being considered by the Commission is to clarify elements of the regulatory test that may currently be considered ambiguous and open to interpretation.

The Commission considerations on how the regulatory test should be amended to reflect the concerns of interested parties are outlined below.

3.2.2 Alternative projects

The current regulatory test does not provide a criterion nor does it define how to select an alternative project. The Commission in its paper promulgating the regulatory test noted:

> "the Commission was concerned that the obligation on the network planner to assess the optimality of a proposed augmentation with respect to alternative projects (eg generation, demand side etc), timing and development scenarios was too open-ended. Consequently, the Commission has amended the Regulatory Test so that the assessment of market benefits is respect to a finite, but unspecified, number of alternatives. While the Commission has not been prescriptive with this element of the test, it would anticipate that the number of alternatives considered would be proportional to the size and/or importance of the proposed augmentation."

In its evaluation of the SNI Option and SNOVIC Option, NEMMCO applied the following criteria in its assessment of which alternative projects should be taken into account when applying the regulatory test:

- "the project should be a genuine alternative to the project being assessed, ie, a <u>substitute</u>; and
- the project should also be <u>practicable</u>

Substitute

For a proposal to be a substitute:

- the outcomes delivered by the proposal should be similar to those delivered by the project; and
- the proposal should become operational in a similar time frame to the project.

Practicable

In considering the practicability of a proposal, NEMMCO considers that the following issues need to be considered:

- the technical feasibility of the additional proposal;
- the commercial feasibility of the additional proposal; and
- having regard to the above, whether there is a proponent or likely to be a proponent for the proposal."

During the NET review of the SNI decision, the following was noted with respect to alternative projects

> From an economic perspective, the term 'alternative' implies projects with attributes such that, were they do proceed, would materially affect the net market benefit calculated for the other projects being considered. In general, these will be projects where the factors contributing to the net benefit are of a similar nature. The source of benefits need not be (and indeed, and unlikely to be) exactly the same for each of the alternative projects considered. However, providing they have a sufficient degree of substitutability, the net market benefits of each will be materially affected by the existence, or not, of the other alternatives. Without this substitutability it would be difficult to limit the number of projects considered in the assessment to a practicable number. [3]

The Commission is of the view that the substitute and practicable requirements seem appropriate when defining an alternative project, as this allows feasible projects which may be preferred to the proposed augmentation to be considered.

However, one issue which was subject to considerable debate at the NET was whether "a proponent" for an alternative project is an indication of the practicability of that project. On this issue the majority view at the NET stated that an alternative project:

> is not necessarily rejected because there is no present proponent. However the absence of a present proponent, or the absence of a likelihood of a future proponent is highly relevant to the question of whether the project is a practicable alternative.

There were suggestions that the proponent criterion undermines a TNSPs' ability to carry out a sensible cost/benefit analysis by preventing a TNSP from considering otherwise feasible projects that may be preferred to the proposed augmentation. [4] It also encourages gaming by transmission companies and encourages those companies to mix socially desirable augmentations with socially undesirable augmentations.

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3 Witness Statement of Gregory Houston for NET (28 June 2002)

4 in the event a NSP is proposing a new interconnector, the NEMMCO approach means that the NSP is able to prevent other NSPs from considering alternative proposals that require any modifications to the NSP's assets unless it gains the NSP's approval. If the NSP wishes to ensure that its proposal passes the regulatory test (in that it is preferred to any alternative project under a coat/benefit analysis) then the NSP will withhold it approval on alternative projects.

It was also noted that incorporating the proponent criterion into the definition of an alternative project is inconsistent with clause 5.5.6 of the code which states that in the competitive sectors of the market, it is not necessary for specific proponents of a project to be identified to justify the inclusion of that project in an analysis under the regulatory test.

However, there have been suggestions that the existence of a proponent may be a shorthand way of showing that a project is both commercially and technically feasible, and that if a project has a proponent, this would be sufficient to establish that it is commercially and technically feasible.

The Commission is of the view that it is not necessary for the proponent criteria to be linked to the practicability of an alternative project, as this would eliminate projects which seem technically and commercially feasible from the analysis or other legitimate proposals. The Commission believe that including a proponent criterion in the alternative project definition may also lead to gaming by the TNSP who will have the ability to determine which projects are considered under the regulatory test, and to only agree to be a proponent for its preferred projects. Further, the Commission notes that proponents are not required when considering generation as an alternative project in accordance with clause 5.5.6 of the code and should therefore not be required when considering transmission alternatives either.

However, the Commission considers that linking a proponent criterion with the definition of an alternative project would not exclude the possibility for cheaper options to eventuate which could provide higher net benefit than the project being considered. This could also provide market signals to other participants that there may be opportunities in that region.

Therefore, after considering the above, the Commission believes that the following criterion should be used when deciding which alternative project should be taken into account in applying the regulatory test:

- have a clearly identifiable proponent, or
- (a) the project should be a genuine alternative to the project being assessed, ie, a <u>substitute</u>; and
- (b) the project should also be <u>practicable</u>.

Substitute

For a proposal to be a substitute:

- the outcomes delivered by the proposal should be <u>similar</u> to those delivered by the project; and
- the proposal should become operational in a <u>similar time frame</u> to the project.

Practicable

In considering the practicability of a proposal, the following issues need to be considered:

- the technical feasibility of the additional proposal; and
- the commercial feasibility of the additional proposal.

In regard to the number of alternatives to consider, the Commission does not believe that it is appropriate to strictly define the number of alternatives to consider when assessing a proposed augmentation under the regulatory test, as this will vary from case to case. The Commission is still of the view that the number of alternatives considered should be proportional to the size and/or importance of the proposed augmentation.

3.2.3 Market benefits

The regulatory test defines market benefits as

> the total net benefits of the proposed augmentation to all those who produce, distribute and consumer electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios

The regulatory test assesses the benefits to the entire market of specific projects. Wealth transfers between generators and consumers are ignored. In addition 'indirect impacts' on non-market participants (such as increases in economy wide productivity as a result of lower electricity prices) are not included in the analysis. The regulatory test also makes clear that only those costs and benefits that can be measured in terms of the financial transactions in the market should be included in the analysis.

It was noted during NET that the main costs and benefits arising from the impact of a particular project on the NEM arise from the impact of the project on the operations of the NEM[5], and the impact of the project on the pattern of future investment in the NEM[6].

ROAM Consulting classified four types of benefits in its assessment of SNI. These included reduction in energy costs, capacity deferrals-capex and opex (capital costs saved in deferring the need to build new generators in the future), reliability benefits, and deferral of network upgrades. Within these groups, ROAM identifies the following benefits:

1. benefits of savings in fuel consumption
    a. Differences in dispatch patterns
    b. Differences in fuel costs

5 For example changes in pattern of dispatch arising from a particular project will result in changes in fuel costs, energy losses over the transmission and distribution network, the extent of unserved energy and ancillary service requirement

6 Changes in the pattern of future investment in the NEM will also have costs and benefits, associated with the bringing forward or deferral/ avoidance of investment

2. benefits of reduction in voluntary load curtailment
    a. reduction in demand-side curtailment
3. benefits of reduction in involuntary load shedding
    a. total volume of VoLL generation forecast
    b. equivalent savings in reduction in loss of load
4. benefits in capital deferrals
    a. deferment of market entry plant
    b. deferment of reliability entry plant
    c. differences in capital costs
    d. differences in the operational and maintenance costs
    e. deferment of transmission investments
5. benefits of reduction in transmission losses
6. benefits of reductions in ancillary services.

It has been noted in submissions that the costs and benefits assessed in relation to one project need not be the same as those assessed under another. However, the Commission notes that TNSPs who have applied the regulatory test identified benefits similar to those identified in ROAM Consulting's assessment of benefits for the SNI Option.

Therefore, the Commission proposes that a list of the above market benefits identified in the ROAM Consulting's report be included as 'examples' after the definition of 'market benefits' in the regulatory test.

3.2.4 Costs

The regulatory test defines costs as

> the total cost of the *augmentation* to all those who produce, distribute or consumer electricity in the National Electricity Market. Any requirements in note 1 to 9, inclusive, on the methodology to be used to calculate the *market benefits* of a *proposed augmentation* should also read as a requirement on the methodology to be used to calculate the cost of an *augmentation*.

It was noted during the NET review of NEMMCO's SNI Option determination that the principal source of costs in respect of new network investment include:

- the capital costs incurred prior to commissioning;
- operating and maintenance costs over the operating life of the project; and

- costs that arise from losses associated with the power flows.[7]

The IRPC identifies the following costs for its assessment of the SNI Option:

- capital costs of the SNI Option; and
- operating and maintenance costs over the operating life of the project

In its SNOVIC assessment, IRPC also identifies ancillary service costs as well as those identified above.

There has been little controversy regarding what costs should be included in the assessment of an augmentation under the regulatory test. The Commission notes that in the application of the regulatory test by TNSPs and NEMMCO, the above costs have been identified. The Commission is of the view that in addition to the costs identified above, the cost of disruption to the NEM for testing of augmentations or upgrades should also be included. The Commission considers that the above costs, as well as the cost testing be included as examples after the definition of "costs" in the regulatory test.

3.2.5 Committed project/ anticipated project

For modelling purposes the regulatory test requires that the proponent identify those proposals which are committed and those which are anticipated. The results of the regulatory test depend on how particular projects are classified. Committed projects identified in the assessment are considered in the 'base case' or in all market development scenarios, whereas anticipated projects are considered in some but not all scenarios.

NEMMCO adopts the following criteria for committed projects in its Statement of Opportunities (SOO):

1. the proponent has purchased/settled/acquired land (or legal proceedings to acquire the land) for the construction of the proposed development.
2. contracts for the supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductor, terminal station equipment) should be finalised and executed, including any provisions for cancellation payments.
3. the proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement.

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7 It was noted that uncertainty in the estimation of costs can arise from, among others, project lead time (the later the estimated commissioning date for the project in question, or for the alternatives under consideration, the greater the extent for cost uncertainty), and project type (projects may differ in their technological maturity and hence their risk of failure, in their environmental impact and hence sustainability to delay during the planning process, and in their location for example, generation location decisions are more difficult to forecast than specific interconnection projects.

4. the financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.

5. construction of the proposal must either have commenced or a firm commencement date must have been set.

The Commission is of the view that the above criteria should be used to determine whether a project is committed. Adopting such a criterion for the regulatory test will provide consistency with the SOO and provide less confusion in respect of determining whether a project is committed.

The Commission considers that the above criterion could be modified for the purposes of defining anticipated projects.

The Commission proposes the following criteria for an anticipated project for the purpose of the regulatory test be applied:

1. the proponent is in the process of purchasing/settling/acquiring land (or legal proceedings to acquire the land) for the construction of the proposed development.

2. the proponent is in the process of setting up contracts for the supply and construction of the major components of the plant and equipment (such as generators, turbines, boilers, transmission towers, conductor, terminal station equipment), including any provisions for cancellation payments.

3. the proponent is in the process of obtaining all required planning consents, construction approvals and licenses, including any necessary environmental impact statement.

4. the proponent is in the process of preparing financing arrangements for the proposal, including any debt plans.

3.2.6 Commercial discount rate

There have been questions raised as to what the appropriate discount rate to use should be. The results of the regulatory test will depend on the discount rate used in the NPV analysis. The regulatory test requires that sensitivity analysis be undertaken for the discount rate to assess the robustness of the NPV results.

In its review to the Commission, Ernst & Young[8] noted that

> *"for the purpose of calculating an NPV of anticipated benefits, a commercial discount rate should be used. This will remove a potential source of bias between generation and transmission options".*

The Commission has previously indicated that

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8 Ernst & Young, *Review of the assessment criterion for new interconnectors and network augmentation*, Final Report to the Australian Competition and Consumer Commission, March 1999

> *"electricity networks are commercial activities which transport electricity from generators to customers and facilitate competition between remote and local generation. Consequently, investment in electricity networks can crowd out investment in competitive activities. In order to ensure that regulated network investments are undertaken in a competitively neutral way in comparison to generation and non-regulated investments, the Commission has accepted the argument that a commercial discount rate should be used".*

The Commission further noted that

> *"the net present value calculation should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector"*[9]

Submissions to the Issues Paper have indicated that a commercial discount rate is appropriate for calculating the NPV of the projects. It was noted that the use of a discount rate for regulated investments applicable to an equivalent private investment in the electricity sector is appropriate, consistent with the uniform treatment of regulated and unregulated projects.

The regulatory test does not specify a method for estimating the discount rate to be applied in the regulatory test or whether the discount rate should be a weighted average cost of capital (WACC) or equity return. It also does not specify whether it should be expressed in pre-tax or post tax basis, or in nominal or real terms. The Commission applies a post-tax nominal WACC in its revenue cap decisions.

The post-tax nominal WACC as defined by the formula proposed by Officer[10] and stated in the Commission's Draft Statement of Principles for the Regulation of Transmission Revenue is:

$$W = r_e \frac{(1 - T)}{(1 - T(1 - \gamma))} \frac{E}{V} + r_d (1 - T) \frac{D}{V}$$

where:

r_e = required rate of return on equity, after company tax;

r_d = pre-tax weighted average cost of debt;

T = effective tax rate;

E = market value of equity;

D = market value of debt;

V = market value of debt plus equity; and

γ = value between 0 and 1 to reflect the fact that an investor may not

9 ACCC 'Regulatory Test for Interconnectors and Network Augmentations", 15 December 1999. Page 21

10 Officer R.R. 1994, The cost of capital of a company under an imputation tax system , *Accounting and Finance*, 34 1, May

benefit to the full value of imputation credit implied by the tax payment of the company.

The Commission refers interested parties to its "Draft Statement of Principles for the Regulation of Transmission Revenue" for a discussion and explanation of the parameters noted above.

In determining whether to use a real, nominal, pre or post tax WACC, the Commission notes that the guiding principle in selecting a discount rate is that the discount rate used should be consistent with the cash flows being discounted. In respect of whether the discount rate is in real or nominal terms will depend on whether the cash flows calculated are in real or nominal terms. In previous applications of the regulatory test, a real commercial discount rate has been used to assess the NPV of the cash flows. As market benefits being discounted are before debt and interest payments and exclude tax, it would appear appropriate that a pre-tax real discount rate be used for the purpose of the regulatory test.

In converting the post-tax nominal WACC formula noted above, there are two different conversion methods. First, the traditional conversion method as illustrated in the NEC (Schedule 6.1, 5.5.4) adjusts for taxation and then for inflation. Second, the Macquarie 'reverse conversion' method adjusts for inflation first and then for taxation. Both conversion methods provide slightly differing results, however the Commission considers either as appropriate to use in evaluating the NPV of a proposed augmentation as there does not appear to be a material difference.

3.2.7 VoLL

For the purpose of the regulatory test, VoLL is used as an input in determining the market benefits and costs. There has been confusion surrounding what the appropriate VoLL level should be used for the purpose of the regulatory test, and whether the value should be the value specified in the code or another.

Clause 3.9.4 of the code defines VoLL as

(a) VoLL is a price cap to be applied to dispatch prices

(b) the value of VoLL will be:

(1) on or before 31 March 2002, $5,000/MWh; and

(2) on and from 1 April 2002, $10,000MWh, subject to an annual review by the reliability panel in accordance with clause 3.9.4(c).

The Commission considers that the ensure consistency with the code, the value of VoLL for the purpose of the regulatory test should be as specified in clause 3.9.4 - that is, $10,000/MWh.

3.2.8 Reliability augmentation

The test for reliability augmentation does not require "net market benefits" to be maximised, nor is it subject to dispute by market participants.

The Commission notes that there were a number of concerns raised by interested parties with respect to the reliability limb of the regulatory test. A number of parties argue that the test dealing with reliability driven augmentation does not place sufficient accountability on the proponent, and that the reliability criteria needs to justified in their own right. However, it has also been noted that the reliability augmentation stream of the test was designed to ensure TNSPs are required to undergo a rigorous and public investment assessment process without it imposing impossible barriers to TNSPs in terms of being able to meet statutory designated reliability standard obligation, and that this particular stream of the test is working well and therefore should not be changed.

The Code defines a reliability augmentation as

> A *transmission network augmentation* that is necessitated solely by inability to meet the minimum *network* performance requirements set out in schedule 5.1 or in relevant legislation, regulations or any statutory instrument of a *participating jurisdiction*".

The NDR code changes provide that the IRPC is required to develop and publish guidance for assessing whether or not a proposed new small network asset or a new large network asset is a reliability augmentation (clause 5.6.3(1)). The NDR code change Determination also notes that:

> in discussions with the Commission, NECA advised that the reliability guidelines should summarise the main aspects of Schedule 5.1 of the Code and would contain reference to relevant jurisdictional legislation and regulations concerning reliability augmentation".

Recognising the concerns raised by interested parties, the Commission proposes to incorporate into the regulatory test notes on reliability driven augmentation which would require a NSP to disclose the following information in respect of a reliability driven augmentation:

- cost of the augmentation;
- whether the augmentation meets a code or jurisdictional objectives;
- what the current restriction is on the network and why the proposed augmentation is required;
- implications to the system or network if the proposed augmentation does not proceed; and
- the benefits that the augmentation can provide.

3.2.9 Conclusion

The Commission has attempted to clarify those elements of the regulatory test which it believes has been subject to misinterpretation or confusion. The definitions that it believes should be included into the regulatory test have largely been based on existing applications of the regulatory test or from the Commission's work through other areas of the Trade Practices Act. The changes put forward by the Commission will hopefully enable a more consistent application of the regulatory test across the regions and minimise potential disputes that may arise from time to time. The Commission now invites interested parties to comment on the appropriateness of its suggestions.

3.3 Competition test

3.3.1 Introduction

The Commission recognises that one of the biggest criticisms of the regulatory test is that it does not recognise competition benefits. Competition benefits arise from increased competition between generators, and the reduction in market power, resulting from free flowing interconnectors. A competition benefits test may therefore ensure that all allocative efficiency benefits, market prices are at marginal cost, and dynamic efficiency benefits, eliminating inefficient generator entry, of network augmentations are captured. Therefore, the third option that the Commission will consider in its review of the regulatory test is whether to include a competition test.

At this stage, the Commission does not have any views on whether the competition test should be recognised as a benefit to be measured within the existing regulatory test framework, or to be applied as a separate test. The Commission is seeking comments from interested parties on this matter.

This section considers a number of approaches to measuring competition benefits. However, one of the Commission's key objectives in developing a competition based test is that it must be objective and robust over a range of market development scenarios.

3.3.2 Competition benefits tests

Market Simulations

Modelling bidding behaviour and pool prices is supported by some parties and is currently required under Note 6 of the regulatory test. Note 6 of the regulatory test states two approaches to market development must be considered, one of which is the "market driven market development" approach which requires that "forecasts of spot price trends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes". However, the Commission notes that in practice, Long Run Marginal Cost (LRMC) bidding has been used to proxy the actual market bidding and prices. The Commission believes that the information from projected bidding behaviour may be used to develop an index which takes the difference between the forecast pool price and both the SRMC and LRMC of generators in the NEM as ascribes the difference to the transmission augmentation.

The main advantage of this approach is that, if modelled correctly, it will accurately measure long term competition benefits that could be captured by an augmentation. Further this approach could also be applied equally within regions as well as between regions.

However, the main criticism of this approach is that, as with any modelling, it will be subject to the assumptions, inputs and modelling techniques employed. The Commission is concerned that this will potentially result in an application being subject to the appeals process set out in the code.

Powerlink's Public Benefits Competition test

Similar to the Market Simulation analysis, Powerlink suggests that the regulatory test could be expanded to include an option "public benefit test", which would provide the option to incorporate competition and other benefits which would include by not be limited to:

- actual pool price outcomes;
- the consideration of strategic bidding scenarios, and
- major load development scenarios.

However, Powerlink suggests that it only be applied in circumstances where

- historical evidence exists that wholesale prices have been significantly above marginal costs;
- market power occurs or will occur, necessitating a definition of when market power arises; and
- overcoming a particular network limitation is considered sufficiently important by one or more jurisdictions.

If the Commission were to adopt such a test it is concerned that the analysis will result in significant delays in any application of a regulatory test to a proposed interconnector. The criteria proposed by Powerlink are also highly subjective and are likely to be disputed by interested parties on how to appropriately capture those benefits.

Hirschmann-Herfindahl index

It is quite common to model competition between electricity generators as a form of Cournot competition – that is, each generating firm is assumed to compete by choosing a quantity of output taking the output of the other firms as given. One of the predictions of this assumption is that the level of market power in the market is determined by the market structure. More specifically, under Cournot competition the Lerner index (a measure of market power) is equal to the Herfindahl-Hirshmann index divided by the elasticity of demand, i.e.,

$$\frac{P - \bar{c}}{P} = \frac{HHI}{e}$$

where P is the market price, $\bar{c}$ is (a weighted average of) marginal cost, HHI is the Herfindahl-Hirschmann index (i.e,. the sum of the squares of the market shares of the firms in the market) and e is the elasticity of demand.

However, the Commission notes that this relationship only holds when the firms in the market are not capacity constrained. That is the firms are not able to expand their output in response to an increase in the market price. In practice, some generators may be capacity constrained. In this circumstance the HHI measure gives a misleading indication of the degree of market power in the market.

One way to overcome this has been suggested by Dr Darryl Biggar in a paper for the OECD[11]. He suggests replacing the HHI with an "adjusted HHI". The "adjusted HHI" is calculated as follows:

$$HHI^{adj} = \sum_{i=1}^{m} s_i (s_i + \bar{s})$$

where there are *m* unconstrained firms, with a market share s_i and the total market share of the constrained firms is $\bar{s}$.

The advantage of the "adjusted HHI" is that the level of market power depends on the market share of all the unconstrained generators and not just the largest generators. In addition, this approach allows for the possibility of market power at even small levels of demand, if one firm has a cost advantage its market share will increase as demand decreases. Additionally, this approach takes into account the elasticity of demand in measuring the market power.

However, it would still need to be modelled over a range of demand and supply projections using a number of simplifying assumptions.

Residual Supply Analysis

Internationally, the Commission is only aware of the Californian Independent System Operator (CAISO) having conducted a competition based assessment on a proposed transmission augmentation. On 24 September 2001, the CAISO released its secondary report on the potential options for expanding Path 15, a transmission line linking mid with northern California.[12] The Primary report, released in 15 September 2001, used a similar process to the Commission's regulatory test assessment, where it assumed perfectly competitive electricity markets where prices reflect marginal cost and no single supplier can manipulate market prices.

The CAISO's secondary study looks at two potential benefits from upgrading Path 15 arising from the mitigation of generator market power in northern California.

The approach used in the study is to:

1) Measure the extent to which suppliers may be able to exercise market power in Northern California in the year 2005 under the various supply scenarios;

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11 Dr Darryl Biggar; OECD, 2001

12 "Potential Economic Benefits to California Load from Expanding Path 15 – Year 2005 Prospect".

2) Calculate the cost impact this market power may have to northern Californian load; and

3) Estimate the extent to which the ability to exercise market power and its corresponding cost impact to load is mitigated by the proposed transmission expansion of Path 15.

The method used to measure market power is a Residual Supply Index (RSI).

Rather than assuming a particular form of competition (such as Cournot competition), the CAISO assumes that there is a linear relationship between the Lerner index and what it calls the "Residual Supply Index". The RSI is a measure of the ratio of the total capacity of all but the largest supplier and the total demand. An RSI of less than 1 signifies that at least some of the output of the largest supplier is essential for meeting the market demand. The assumption is that in this case the largest supplier would have significant market power.

The CAISO uses data for the year 2000 to estimate the relationship between the Lerner index, the RSI and a measure of total system load, in the form:

$$\text{Lerner Index}_t = a + b*\text{RSI}_t + c*\text{Load}_t + \varepsilon_t$$ [13]

The CAISO finds that the coefficients are statistically significant in all of the four different scenarios it considers (peak and off-peak season and peak and off-peak hours). As an example, the CAISO finds that a 10% increase in the RSI during peak hours in the peak season leads to approximately a 15% drop in the Lerner index. This simple equation is able to explain between 34% and 63% of the variation in the level of market power.

Using the assumption that this relationship is maintained over time (with and without the network upgrade), the CAISO is able to calculate the market prices in a variety of market scenarios with and without the network augmentation. As a result, the CAISO is able to estimate the benefits of the proposed project. The study found that under a number of scenarios the potential annual benefits to load in northern California range from US$208 million to US$1.3 billion, with the cost of the transmission project at US$300 million. This compares to the potential benefits of around $500 million delivered under the primary study.

This approach has the advantage of being relatively simple and straightforward. However, the Commission believes that it might be subject to a number of criticisms. In particular, the approach of focusing on the RSI ignores all elements of the market structure apart from the market share of the largest suppliers. In addition, the formulation ignores the possibility that some suppliers could be capacity constrained. The market power of the largest supplier might be expected to be much larger if the other firms are capacity constrained. The Commission also believes that the formulation ignores the scope for cost differences between the generating firms. Further, over time the Commission would not expect that the relationship between the RSI and the Lerner index to remain constant over time.

13 CAISO (2002), page 15.

Commercial benefits analysis

A measure of the historic short term competition benefits may be derived from the Inter-Regional Settlements Residues (IRSRs). The Commission believes that this approach may be a first step towards the development of Financial Transmission Rights (FTRs) in the NEM and along the lines recommended by the Council of Australian Governments Energy Markets Review. Its recommendation was for new regulated intra-regional augmentation proposals to be subject to a "commercial" benefits test which takes into account spot price separation between regions.

The methodology being considered by the Commission would involve using a rolling average of the sum of the IRSRs between two regions with the rolling average being for either 12 or 24 months prior to an assessment of an interconnector against the regulatory test. Based on the table below, if an interconnector was constructed in 2002 between the New South Wales and Snowy Regions a proponent could include $15.5 million (based on a 12 month rolling average) or $22 million (based on a 24 month rolling average) of competition benefits into the analysis.

Table 1 – Inter-Regional Settlements Residues

Interconnector	Residues		
	1999 ($'000's)	2000 ($'000's)	2001 ($'000's)
(QNI) Queensland – New South Wales	0	-1	4,367
(QNI) New South Wales – Queensland	0	1	5,136
New South Wales – Snowy	4,707	190	84
Snowy – New South Wales	6	5,857	15,514
Snowy – Victoria	7,967	40,314	46,782
Victoria – Snowy	3,961	3,481	6,879
Victoria – South Australia	108,594	51,481	9,704
South Australia – Victoria	0	1261	425

NEMMCO – 2002 Statement of Opportunities

The main attraction of this proposal is in its simplicity. This method attempts to approximate similar benefits to those that will be captured under a regime of FTRs. While the Commission recognises that at times when the interconnectors do not flow, no IRSRs accrue thereby undervaluing competition benefits, the measure is an objective one.

However, the Commission acknowledges that this measure lacks economic rigour and is therefore a crude approximation of competition benefits. The measure also signals future interconnection using historic information rather than future information. A modified approach may consider forecasting the level of IRSRs but this detracts from the simplicity of the approach, and it would be better to run market simulations rather than attempt to forecast IRSRs. Another downside of the measure is that it cannot be applied to intra-regional investments.

Stanwell Competition Index

A competition index, along the lines proposed by Stanwell may be one way of incorporating competition benefits into the regulatory test. The Stanwell competition index uses qualitative measures of competition benefits rather than quantitative including:

- the number of consumers affected by the network limitation;
- the incremental electricity capacity supplied to the market following augmentation;
- the fuel mix of the incremental electrical capacity (indicating underlying cost structure); and
- the number of independent entities supplying the market following augmentation;

The Commission's concern with using a qualitatitve measure is that it is a subjective measure which increases the risk of dispute.

3.3.3 Conclusion

The Commission has outlined a number of possible competition benefits tests for interested parties consideration. The Commission now invites interested parties to comment on:

- the appropriateness and practicability of the methods for calculating competition benefits as outlined above;
- whether the measures outlined above achieve the Commission's objectives of developing a robust measure across a range of market development scenarios; and
- whether the competition benefits test should be included into the regulatory test or be applied as a separate test.

Interested parties may also wish to submit alternative measures for the Commission's considerations.

4. Commission's process

The Commission invites interested parties to consider and comment on the options outlined in Chapter 3.

Submissions can be sent electronically to: electricity.group@accc.gov.au. Alternatively, written submissions or submissions on disk, in either Word 7.0 or PDF format, can be sent to:

Mr Sebastian Roberts
A/g General Manager
Regulatory Affairs – Electricity
Australian Competition and Consumer Commission
PO Box 1199
DICKSON ACT 2606

The closing date for submissions is **Friday 28 March 2003**.

Comments provided by interested parties will be incorporated into the Commission's draft decision. The Commission will consult on its draft decision prior to releasing its final decision where, if necessary, in accordance with clause 5.6.5A of the code, the Commission will promulgate changes to the *regulatory test*. The Commission considers that the *regulatory test* will ultimately form part of its Regulatory Principles.

Further enquiries should be directed to Louis Tirpcou on (03) 9290 1905.

Appendix A Regulatory test

Preamble

The Australian Competition and Consumer Commission promulgates this regulatory test in accordance with clause 5.6.5(q)(1) of the National Electricity Code (the Code).

The regulatory test is to be applied:

(d) to *transmission system* or *distribution system* augmentation proposals in accordance with clause 5.6.2 of the Code (*augmentation*);

(e) by NEMMCO and the Inter-regional Planning Committee to augmentation options identified under clause 5.6.5 of the Code other than applications for new interconnectors in accordance with clause 5.6.6 of the Code (*augmentation option*); and

(f) by NEMMCO and the Inter-regional Planning Committee to applications for new interconnectors across regions in accordance with clause 5.6.5 and 5.6.6 of the Code (*new interconnectors*).

In this test, *augmentations, augmentation options* and *new interconnectors* are called *proposed augmentations*.

The regulatory test

The Commission has determined that the regulatory test is as follows:

A *new interconnector or an augmentation option* satisfies this test if it maximises the *net present value* of the *market benefit* having regard to a number of alternative projects, timings and market development scenarios; and

An *augmentation* satisfies this test if -

(c) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or

(d) in all other cases – the augmentation maximises the net present value of the *market benefit*

having regard to a number of alternative projects, timings and market development scenarios.

For the purposes of the test:

(a) *market benefit* means the total net benefits of the *proposed augmentation* to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios;

(b) *cost* means the total cost of the *augmentation* to all those who produce, distribute or consume electricity in the National Electricity Market. Any requirements in notes 1 to 9, inclusive, on the methodology to be used to calculate the *market benefit* of a *proposed augmentation* should also be read as a requirement on the methodology to be used to calculate the *cost* of an *augmentation*;

(c) the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector;

(d) the calculation of the *market benefit* or *cost* should encompass sensitivity analysis with respect to the key input variables, including capital and operating costs, the discount rate and the *commissioning* date, in order to demonstrate the robustness of the analysis;

(e) a *proposed augmentation* maximises the *market benefit* if it achieves a greater *market benefit* in most (although not all) credible scenarios; and

(f) an *augmentation* minimises the *cost* if it achieves a lower *cost* in most (although not all) credible scenarios.

Notes on the methodology to be used in the regulatory test to a proposed augmentation

(1) In determining the *market benefit*, the following information should be considered:

(a) the cost of the *proposed augmentation*;

(b) reasonable forecasts of:

i. electricity demand (modified where appropriate to take into account demand side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);

ii. the value of energy to electricity consumers as reflected in the level of VoLL;

iii. the efficient operating costs of competitively supplying energy to meet forecast demand from existing, *committed, anticipated and modelled projects* including demand side and generation projects;

iv. the capital costs of *committed*, *anticipated* and *modelled projects* including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;

v. the cost of providing sufficient ancillary services to meet the forecast demand; and

vi. the capital and operating costs of other regulated network and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.

(c) the proponent's nominated *construction timetable* must include a *start of construction*, *construction time* and *commissioning*, where:

i. *start of construction* means the date at which construction is required to commence in order to meet the *commissioning* date, taking into consideration the *construction time* nominated by the proponent;

ii. *construction time* is the time nominated by the proponent to order equipment and build the project and does not include the time required to obtain environmental, regulatory or planning approval; and

iii. *commissioning* means the date, nominated by the proponent, on which the project is to be placed into commercial operation.

(2) In determining the *market benefit*, it should be considered whether the *proposed augmentation* will enable:

(a) a *Transmission Network Service Provider* to provide both *prescribed* and other services; or

(b) a Distribution Network Service Provider to provide both *prescribed distribution services* and other services

If it does, the costs and benefits associated with the other services should be disregarded. The allocation of costs between *prescribed* and other services must be consistent with the *Transmission Ring-Fencing Guidelines*. The allocation of costs between *prescribed distribution services* and other services must be consistent with the relevant *Distribution Ring-Fencing Guidelines*.

(3) The costs identified in determining the *market benefit* should include the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution. An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost. Any other costs should be disregarded.

(4) In determining the *market benefit*, any benefit or cost which cannot be measured as a benefit or cost to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the *Transmission Ring-Fencing Guidelines* and/or *Distribution Ring-Fencing Guidelines* (as appropriate). Only direct costs and benefits (associated with a partial equilibrium analysis) should

be included and any additional indirect costs or benefits (associated with a general equilibrium analysis) should be excluded from the assessment.

(5) In determining the *market benefit*, the analysis should include modelling a range of reasonable alternative market development scenarios, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project *commissioning* dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative *construction timetables* as nominated by the proponent. These scenarios should include projects undertaken to ensure that relevant reliability standards are met.

These market development scenarios should include:

(a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (*committed projects*);

(b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (*anticipated projects*);

(c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant (*modelled projects*); and

(d) any other projects identified during the consultation process.

(6) Modelled projects should be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.

(a) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs.

(b) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.

(7) In determining the *market benefit*, the *proposed augmentation* should not pre-empt nor distort potential unregulated developments including network, generation and demand side developments. To this end:

(a) a *proposed augmentation* must not be determined to satisfy this test more than 12 months before the *start of construction* date;

(b) a *proposed augmentation* will cease to satisfy this test if it has not commenced operation by 12 months after the *commissioning* date unless there has been a delay clearly due to unforeseen circumstances;

(c) unless there are exceptional circumstances, *new interconnectors* must not be determined to satisfy this test if *start of construction* is within 18 months of the project's need being first identified in a network's annual planning review or NEMMCO's statement of opportunities (or in some similar published document in the period prior to 13 December 1998).

(8) The consultation process for determining whether a *proposed augmentation* satisfies this test must be an open process, with interested parties having an opportunity to provide input and understand how the benefits have been measured and how the decision has been made. Specific consultation is required on:

(a) identifying *committed projects* and *anticipated projects*;

(b) setting input assumptions such as fuel costs and load growth;

(c) modelling market behaviour and considering whether the market development scenarios are realistic;

(d) the proponent's *construction timetable*;

(e) understanding how benefits will be allocated; and

(f) understanding how a decision has been made.

(9) Any information which may have a material impact on the determination of *market benefit* and which comes to light at any time before the final decision must be considered and made available to interested parties.

Appendix B Submissions

The following submissions were received by the Commission in response to the Review of the regulatory test Issues Paper:

1. VENCorp;
2. Reliability and Network Planning Panel;
3. Stanwell Corporation Ltd;
4. NSW Treasury;
5. Loy Yang Power;
6. TransEnergie Australia;
7. Snowy Hydro;
8. Powerlink;
9. Edison;
10. ElectraNet SA;
11. Origin Energy;
12. TransGrid;
13. SPI PowerNet;
14. NRG Flinders;
15. Enertrade;
16. CS Energy;
17. NEMMCO;
18. TXU; and
19. Electricity Supply Association of Australia Limited (ESAA)